BEFORE THE
PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA

DOCKET NO. 2020-264-E
DOCKET NO. 2020-265-E

In the Matter of: Duke Energy Carolinas, LLC's Establishment of Solar Choice Metering Tariffs Pursuant to S.C. Code Ann. Section 58-40-20 Duke Energy Progress, LLC's Establishment of Solar Choice Metering Tariffs Pursuant to S.C. Code Ann. Section 58-40-20	)))))))))))	**REBUTTAL TESTIMONY OF BRADLEY HARRIS FOR DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC**

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bradley ("Brad") Harris, and my business address is 411 Fayetteville Street, Raleigh, North Carolina 27601.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Corporation as a Rates and Regulatory Strategy Manager, where I am responsible for managing strategic rate design reforms in the Carolinas and Florida.

Q. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I previously offered direct testimony in this proceeding on behalf of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC the "Companies").

Q. ARE YOU INCLUDING ANY EXHIBITS IN SUPPORT OF YOUR REBUTTAL TESTIMONY?

A. Yes, I am including an updated Embedded Cost Shift Study (as defined below) as **Harris Rebuttal Exhibit 1**.

Q. WAS THIS EXHIBIT PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

A. Yes, it was.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my rebuttal testimony is to respond to certain items raised in the direct testimony of South Carolina Office of Regulatory Staff's ("ORS") Witness Horii related to the Companies' Embedded Cost of Service ("COS") Studies that were presented as **Harris Direct Exhibit 1** in my direct testimony in these dockets.

Q. CAN YOU PLEASE PROVIDE A SUMMARY OF YOUR REBUTTAL TESTIMONY?

A. Yes. Witness Horii makes several suggestions that violate the approved and accepted ratemaking practices in South Carolina. For example, Witness Horii's allegation that the Companies should use anything other than 1 Summer Coincident Peak ("Summer CP") to establish rates under the NEM tariffs submitted in this proceeding (the "Solar Choice Tariffs") would mean that this subset of customers would take service under rates that are based upon a completely different allocator than <u>all</u> of the other retail electric rates in the Companies' South Carolina service territories. Utilizing a different allocator in this proceeding would not reflect the historical basis on which these costs were incurred and would have significant implications to non-NEM customers. That is precisely the reason that any such change should only be made in a base rate proceeding, which is far different in procedural posture than these NEM-specific dockets. At the end of the day, the Companies utilized Commission-approved methodologies and inputs to create Solar Choice Tariffs that balance the policy goals of Act 62, including the elimination of cost-shift to the "greatest extent practicable." These tariffs were developed via a robust and extensive stakeholder process, that resulted in two stipulations filed in these dockets related to residential and non-residential customers. Finally, I've updated certain calculations in my direct testimony to reflect certain updates made by DEC to its FERC Form 1.

II. EMBEDDED COS STUDY

Q. WOULD YOU LIKE TO MAKE ANY CLARIFICATIONS REGARDING THE COMPANIES' EMBEDDED COS STUDIES?

A. Yes, previously, the Companies' witnesses have referred to my analyses on the embedded unwarranted cost shift arising from NEM as the "Embedded COS Study." In light of the fact that this proceeding is now discussing other COS studies, I would like to avoid confusion by clarifying my terms. From now on, I'll refer to my analysis on the cost shift as the "Embedded Cost Shift Study." The COS studies that are associated with the Companies' 2018 base rate cases will be referred to as the "Embedded COS Studies." The Embedded COS Studies were used to develop the compliance rates filed with the Commission as a result of the Orders in the 2018 base rate cases for DEC and DEP. These are the same base rates that are currently in place for the Companies. The Embedded COS Studies are the basis for all of the Companies' retail pricing and are separate from my analysis on the cost shift.

Q. PLEASE RESTATE THE CONTEXT IN WHICH THE COMPANIES ARE SUBMITTING THE EMBEDDED COST SHIFT STUDIES.

A. The Embedded Cost Shift Studies were submitted to the Commission as a part of the Companies' analysis of the potential for cross-subsidization created by the Solar Choice Tariffs. This analysis was filed along with the Solar Choice Tariffs because

Act 62 requires that the tariffs eliminate cross-subsidization to the "greatest extent practicable." To determine the potential for cross-subsidization, the embedded cost analysis considers historical or "embedded" costs that are ultimately reflected in the Companies' accounting records. These embedded costs are utilized to calculate each utility's revenue requirements and corresponding retail prices. A cross-subsidy exists when one group of customers is not paying its fair share towards the embedded costs. The ORS is contesting the Companies' cross-subsidization analysis based on embedded costs, and specifically the allocation methodology for production (sometimes referred to as generation) and transmission capacity costs.

The Companies do not believe that the Embedded Cost Shift Studies are solely determinative in evaluating cross-subsidization. As such, the Companies also submitted cross-subsidization analyses based on marginal costs. Marginal cost represents the cost of producing one additional unit of energy. The Companies believe that this analysis should also carry significant weight to ensure that customers only pay their fair share for costs.

Q. ORS WITNESS HORII CLAIMS THE COMPANIES' EMBEDDED COST SHIFT STUDIES WERE "BASED ON THE NOW OUTDATED DEC AND DEP 2017 COS STUDIES." IS HE CORRECT THAT THE INFORMATION IS OUTDATED?

A. No. The Embedded COS Studies that are the starting point of the Embedded Cost Shift Studies were developed in mid-2019 as result of the May 2019 Orders in the

2018 base rate cases for DEC and DEP.[1] These are the same base rates that were implemented in 2019, which is around the same time the Companies began the analysis for the Solar Choice docket. These Embedded COS Studies utilize the Summer CP, and are the basis for all of the retail prices in our jurisdictions in South Carolina and reflect the most appropriate basis upon which to set rates for the Solar Choice Tariffs. As such, any change from the established Summer CP methodology for allocating embedded production and transmission capacity costs requires a fundamental rethinking of all of the Companies' retail rates. Not only was this the appropriate analysis to use, it was the most expedient. As the Commission is aware, Act 62 has placed aggressive deadlines on the case participants and the Commission. It was appropriate to use the best analysis the Companies had in hand to initiate discussion and collaboration in hopes of reaching a compromise to bring to the Commission within the statutory time frames requiring an effective tariff by June 1, 2021.

Q. WHY IS THE SUMMER CP STILL AN APPROPRIATE ALLOCATION METHOD?

A. As explained in this proceeding by Witness Hager—who was the Companies' cost of service witness in the last six rate cases for the DEP and DEC—the majority of the production and transmission assets reflected in the Embedded COS Studies were incurred to serve a summer peak, given the fact that both utilities have historically been summer peaking. As noted by Witness Hager, the Commission

[1] Order No. 2019-323, issued in Docket No. 2018-319-E, dated May 21, 2019, and Order No. 2019-341, issued in Docket No. 2018-318-E, dated May 21, 2019.

was silent on the issue in the most recent DEP rate case Order, but stated explicitly in the DEC Order that, "[t]he Commission finds and concludes that for purposes of this proceeding, the Company may continue to use the [Summer CP] methodology for allocation between jurisdictions and among customer classes and that the Company's cost of service methodology is just and reasonable."[2]

Q. ARE THE COMPANIES RECOVERING ANY ADDITIONAL PRODUCTION CAPACITY COSTS INCURRED SINCE THE CONCLUSION OF THE 2018 RATE CASES IN BASE RATES?

A. No, only the costs identified in those proceedings are being recovered in DEC and DEP retail rates. Therefore, any subsequent capital spends on generation or transmission capacity to serve a potential winter peak are not being recovered in any of the Companies' current base rates. In other words, no costs incurred to serve a winter peak since the 2018 base rate cases are being paid by ratepayers and, thus, will not be recovered from retail customers until the implementation of the next base rate case.

Q. BEGINNING ON PAGE 7, LINE 20, WITNESS HORII CONTENDS THAT "THERE IS NO VALID REASON, OTHER THAN CONSISTENCY WITH PAST PRACTICE, FOR KEEPING TO A 1 [SUMMER] CP METHOD WHEN SUPERIOR PROBABILISTIC METHODS ARE ALREADY BEING USED FOR RESOURCE ADEQUACY PLANNING AT DUKE." WAS THE SUMMER CP ONLY APPLIED FOR CONSISTENCY PURPOSES?

[2] Order No. 2019-323 dated May 21, 2019, in Docket No. 2018-319-E, p. 32.

A. No, and this is a fundamental point of disagreement. We believe that the Companies do not have the flexibility to choose an alternative embedded cost allocator for these dockets that has not been previously vetted by the Commission. To do so would be inconsistent with the base rates approved by the Commission and currently being charged to retail customers. Any deviation from the approved Summer CP allocator must be made as a part of a future base rate case. There are numerous policy reasons for this position which I will explain briefly, and which are also discussed in the testimony of Witnesses Hager and Faruqui in this proceeding.

Q. WITNESS HORII NOTES THAT THE COMPANIES' EMBEDDED COS STUDIES ASSUME THE DEC AND DEP SYSTEM PEAKS REMAIN IN THE SUMMER. IS THIS ACCURATE?

A. No, as is reflected in many of the Companies' analyses, rates, and procedures, both DEC and DEP are now winter-planning and thus expect future peaks net of solar generation to occur in the winter. This is in no way inconsistent with the current practice of allocating embedded costs—which were incurred to serve historical summer peaks—using the Summer CP methodology.

Q. WILL THE SOLAR CHOICE TARIFFS CHANGE IF THE COMPANIES PROPOSE, AND THE COMMISSION APPROVES, ANOTHER COST ALLOCATION METHOD FOR PRODUCTION AND TRANSMISSION CAPACITY COSTS IN FUTURE BASE RATE CASES?

A. Yes. As part of future base rate case proceedings, the Embedded Cost Shift Studies will be updated using the most recently approved cost allocation methodology, which will then be factored into the Solar Choice Tariffs to address cost-shift, as appropriate.

Q. WITNESS HORII CALCULATED THE EMBEDDED COST SHIFTS USING INFORMATION FROM THE DEC AND DEP 2016 RESOURCE ADEQUACY STUDIES. DO YOU BELIEVE THAT THE COMPANIES ERRED IN PROPOSING, THE ORS ERRED IN SUPPORTING, AND THE COMMISSION ERRED IN APPROVING CURRENT RATES BASED ON THE 2018 EMBEDDED COS STUDIES IN SPITE OF THE PRIOR PUBLICATION OF THE RESOURCE ADEQUACY STUDIES?

A. No. As stated in the executive summary of the Resource Adequacy Studies "the primary purpose of this study is to provide the Companies' system planners with information on physical reliability that could be expected with various reserve margin planning targets." There is no mention of embedded costs in the these studies because Resource Adequacy Studies are intended to evaluate future system requirements rather than measuring or allocating historical costs. As such, Resource Adequacy Studies are not utilized in base rate cases, which set rates based on historical costs. This is why the Commission decided that the use of the Companies' Embedded COS Studies, which utilized the Summer CP, remained a just and reasonable way to allocate historical production and transmission capacity costs.

Q. WITNESS HORII ARGUES THAT NO NEW EMBEDDED COS STUDIES WOULD BE NEEDED TO EVALUATE THE FULL IMPACT OF A WINTER PEAK. DO YOU AGREE?

A. No. As previously discussed, it is uncertain as to what methodology for allocating embedded production and transmission costs may be appropriate in the future. Even assuming that another allocation methodology should be used, at minimum new embedded COS studies would be required. This is for two reasons:

1) As previously discussed, the Companies cannot use one allocation methodology for one group of customers and a different methodology for another. This would result in an over or under-collection of the revenue requirement.

2) The embedded cross-subsidization analysis in question relies on a unit cost methodology. A unit cost takes the total revenue requirement for a rate class and divides it by the appropriate billing determinant, such as how much energy that rate class consumed in the test year. For example, if $1 million in energy costs are identified then this can be divided by 10 million kWh to arrive at an energy unit cost of 10 cents/kWh. Currently, to produce the production and transmission unit costs, the billing determinant is the residential kW at the summer peak. Changing to a Winter CP would change the revenue requirements and the billing determinants for all rate classes and would require the reallocation of costs. If the Companies were to change to a Winter CP methodology, as Witness Horii suggests, it would require a new embedded COS study for all retail customers to ensure customers are not paying more or less than the revenue requirement.

Q. WITNESS HORII ARGUES THAT "HOW A NEW EMBEDDED COS STUDY MIGHT SHIFT COSTS BETWEEN CLASSES IS NOT A CONCERN THAT THE COMMISSION NEEDS TO ADDRESS IN THIS DOCKET." DO YOU AGREE?

A. No. Section 58-40-20, as implemented by Act 62, requires the Commission to be concerned about cost shifts. It directs the Commission to consider when evaluating the costs and benefits of the net energy metering program "the cost of service implications of customer-generators on the other customers within the same class, including an evaluation of whether customer-generators provide an adequate rate of return to the electrical utility compared to the otherwise applicable rate class when, for analytical purposes only, examined as a separate class within a cost of service study." While it is true that this section is in relation to the generic docket, the legislative intent of this language is clear. The legislation implies that analyzing NEM customers as their own customer class is a relevant and appropriate way to calculate the costs and benefits of a net metering program.

Q. HAVE THE COMPANIES PREVIOUSLY DISCUSSED WITH THE ORS THE ISSUES WITH USING NEW, NON-COMMISSION APPROVED EMBEDDED COST ALLOCATORS TO EVALUATE THE COST SHIFT OF NEM?

A. Yes. Lon Huber, Vice President of Rate Design and Strategic Solutions for Duke Energy Corporation, expressed his concern with using a non-approved embedded cost allocator in a conference call that the Companies conducted with ORS on

December 16, 2020. I also responded to the concerns voiced by Witness Horii in my rebuttal testimony in Docket No. 2019-182-E.

III. MOU

Q. WITNESS HORII CLAIMS THAT "THE MOU'S BINDING AGREEMENTS MAY RESTRICT THE INFORMATION PROVIDED BY [THE COMPANIES] WHICH MAY, IN TURN, PREVENT THE SHARING OF USEFUL INFORMATION IN THIS PROCEEDING." HAVE THE COMPANIES WITHHELD ANY PERTINENT INFORMATION, FAILED TO RESPOND TO ANY DATA REQUESTS OR INQUIRIES, OR ENTERED INTO ANY AGREEMENTS THAT PREVENT THE COMPANIES FROM PRESENTING AN HONEST ANALYSIS?

A. No. To the best of my knowledge, the Companies have responded to all data requests in this proceeding, in addition to any requests for further conversations with the ORS. The Companies have also proactively reached out to the ORS to solicit and answer any additional questions they might have. It is ethical and reasonable for the Companies to arrive at a stipulation with other parties in dockets before the Commission. The Companies have a long history of settling cases before this Commission, including with the ORS, and there is no reason to conclude as Witness Horii has that the Companies would not be forthright and share useful information simply because it reached a stipulation.

IV. PAYBACK PERIODS

Q. PLEASE DISCUSS WITNESS HORII'S SUGGESTION THAT THE COMPANIES SHOULD MODEL A LOWER DEVELOPER MARGIN IN THEIR PAYBACK PERIOD ANALYSIS.

A. The Companies have historically included a 30% adder to the cost of installing rooftop solar systems to account for developer fees and costs. This 30% adder is based on guidance from Guidehouse—a nationally-recognized consultant—which indicated a national third-party owner profit margin assumption of 30%. The Companies' payback analysis also reduced the adder after the phasing out of the Federal Investment Tax Credit ("ITC") to reflect expected changes to the national market for rooftop solar installations. Based on the reasonableness of the 30% profit margin assumption, Congress's recent extension of the ITC, and trends in the national market, the Companies do not believe it is appropriate to lower this adder at this time.

V. "ZERO COST SHIFT" RATES

Q. DO YOU AGREE WITH WITNESS HORII THAT "THE PROPOSED PERMANENT TARIFFS STILL LEAVE NON-SOLAR CUSTOMERS TO BEAR A SUBSTANTIAL COST SHIFT, WHETHER ONE CALCULATES COST SHIFT BASED ON MARGINAL COSTS OR EMBEDDED COSTS"?

A. No. For DEC, our analyses revealed a reduction in the unwarranted cost shift from an embedded perspective of 84% and from a marginal lens of 88%. As previously discussed, the Companies did not attempt to quantify the impact of customer responses to price signals. As Witness Horii notes, if customers respond to price signals, it will lower their cost to serve. Therefore, the reduction in the unwarranted cost shift is likely to be even greater than the estimates the Companies provided. In DEP the same analyses resulted in respective unwarranted cost shift reductions of 100% and 53% under embedded and marginal lenses. Again, this does not include any of the impacts from customer responses to price signals.

I contend that the analyses of the unwarranted cost shift or cross-subsidy demonstrate that the proposed Solar Choice Tariffs substantially reduce the cross-subsidy arising from customer-generators and complies with Act 62's requirement to reduce the cost shift to the greatest extent practicable.

VI. <u>INTERIM RIDERS</u>

Q. DO YOU AGREE WITH WITNESS HORII THAT THE PROPOSED INTERIM RIDERS ARE A SMALL STEP TOWARDS REDUCING THE COST SHIFT?

A. I agree that the interim riders (the "Interim Riders") provide a limited reduction in the cost shifts per customer-generator when compared to the more permanent option that will be effective on January 1, 2022. The Companies had to balance several disparate priorities including the limitation of the Companies' legacy billing systems during a time of transition, Act 62's direction to reduce the cost shift, and Act 62's direction to continue enabling market-driven, private investment in distributed energy resources and the specific timetables for new tariffs as spelled out in Act 62. In order to meet all of these objectives, the Companies developed the Interim Riders. However, the Companies placed parameters upon the Interim Riders to achieve additional protection for non-solar customers, such as the monthly cap on residential solar applications of 1.2 MW-DC for DEC and 300 kW-DC for DEP. The proposed caps effectively mitigate risk to non-participating customers, recognize the full scope of legislative intent, and in doing so obviate the need to place customers on time-of-use ("TOU") netting or include a $10 Basic Facilities Charge as suggested by Witness Horii. This ensures that the number of new customer-generators that are served under the Interim Riders is kept to a reasonable level and minimizes the aggregate cross-subsidy. The Interim Riders provide a glide path towards to the permanent tariffs, while avoiding a disruption in the market for residential rooftop solar.

VII. <u>NON-RESIDENTIAL RIDERS</u>

Q. PLEASE PROVIDE CONTEXT FOR THE COMPANIES' PROPOSALS FOR NON-RESIDENTIAL CUSTOMER-GENERATORS.

A. There are two facts that should be considered regarding non-residential customer-generators. First, as previously discussed in this proceeding and the generic docket, there is a great deal more diversity in the energy usage characteristics of non-residential customer-generators compared to residential customer-generators. The Companies currently do not have enough data to produce a representative non-residential version of its residential customer-generator analysis. It would be inappropriate to modify the energy component of these customer's tariffs, as the Companies proposed with residential customers, without this analysis. Second, most non-residential rate schedules include demand charges, which significantly reduce cross-subsidization.

Q. PLEASE RESPOND TO THE ORS'S RECOMMENDATIONS REGARDING NON-RESIDENTIAL CUSTOMER-GENERATORS.

A. ORS proposed non-residential NEM customers be placed on monthly TOU netting as of January 1, 2022. Updating the TOU periods on all non-residential TOU rate schedules in DEC and DEP is a large undertaking requiring careful consideration and appropriate notice. It would be premature to modify these tariffs without appropriate analysis. Without the data required for an appropriate analysis of non-residential TOU periods, proposing non-residential TOU rate schedules may increase the per customer-generator cross-subsidization. Therefore, the Companies do not recommend this policy change.

Q. HAVE THE COMPANIES DONE ANYTHING TO REDUCE ANY COST SHIFT THAT MIGHT ARISE FROM NON-RESIDENTIAL NEM?

A. Yes. The non-residential Solar Choice riders include monthly netting rather than monthly carryover of excess energy with annual netting. In addition, the biggest risk for cross-subsidization occurs with Small General Service customers who are on rate schedules without demand charges for those with less than 30 kW in demand. In the Companies' stipulation with Alder Energy Systems, LLC, the Companies have proposed putting caps on the growth of these customers. This will ensure that the Commission has an opportunity to address a potential cross-subsidization issue before it materially affects non-solar customers.

VIII. UPDATES TO DEC AND DEP EMBEDDED COST SHIFT STUDIES

Q. DO THE COMPANIES HAVE ANY UPDATES TO THE EMBEDDED COST SHIFT STUDIES?

A. Yes, today, February 22, 2021, DEC updated certain information related to the 2017 system peak in its 2017 FERC Form 1 filed with the FERC. This update corrected an error in the FERC Form 1 where the summer peak was reported an hour too early because of daylight savings. In **Harris Rebuttal Exhibit 1** an updated analysis is provided. Even with this update, there was no substantive change to the conclusions of my analysis. Aside from reflecting the change in the peak hour from hour ended 3pm to hour ending 4pm, nothing else in the methodology for calculating the embedded cost shift has changed.

Q. DOES THIS UPDATE MEAN THE COST OF SERVICE STUDIES UTILIZED IN THE MOST RECENT RATE CASES ALSO NEED TO BE UPDATED?

A. No, only the 2017 FERC Form 1 was updated, which required this update. I have confirmed that the Embedded COS Studies provided in the 2018 base rate cases used the correct hour ended 4pm.

Q. PLEASE SUMMARIZE THE IMPACT OF THIS UPDATE.

A. The update reduces the embedded cross-subsidy under the Permanent Tariffs—as proposed by the Companies—74-95% in DEC and 89-114% in DEP. This is in relatively the same range as the earlier analysis at hour ended 3pm which had the reduction at 93-113% in DEC and 109-145% in DEP. The results are reflected in the below table:

	Unwarranted Cost Shift Per Customer-Generator Bill		
	DEC-SC		
	Full Retail NEM	Stipulation*	Aprox. Percent Reduction
Embedded Cost	$ 43.52	$ 6.93	84%
Marginal Cost	$ 35.80	$ 4.03	88%
	DEP-SC		
	Full Retail NEM	Stipulation*	Aprox. Percent Reduction
Embedded Cost	$ 43.49	$ 0.06	100%
Marginal Cost	$ 52.45	$ 18.12	65%

*Stipulation numbers do not reflect impact of behavioral responses to prices

Q. DOES THIS UPDATE CHANGE YOUR CONCLUSIONS REGARDING THE EMBEDDED COST SHIFT ANALYSIS?

A. No, the Permanent Tariffs still show a very substantial, if not complete, reduction in the embedded cost shift.

IX. CONCLUSION

Q. DOES THIS CONCLUDE YOUR PRE-FILED REBUTTAL TESTIMONY?

A. Yes, it does.

Embedded Cost Study
Docket Nos. 2020-264-E & 2020-265-E
Summary of Results and Rider Adjustments
For the test year ending December 31, 2017

DEP

	RES	RES Settlement
Monthly Cross-Subsidy Range	$38-$50	($5)-$5
Estimated Reduction in Cross-Subsidy		**89%-114%**

DEC

	RS	RE	RS Settlement	RE Settlement
Monthly Cross-Subsidy Range	$44-$55	$31-$41	$10-$20	($7)-$1
Estimated Reduction in Solar Cross-Subsidy			65%-78%	96%-122%

Settlement Weighted Reduction in Solar Cross-Subsidy **74%-95%**

Embedded Cost Study
Docket Nos. 2020-264-E & 2020-265-E
Summary of Results and Rider Adjustments
For the test year ending December 31, 2017

3% Sensitivity Factor for High/Low Scenarios
Applied to NEM COS, Revenue Reduction, and Avoided Cost Payout

DEP

	RES	RES - High	RES - Low	RES Settlement	RES Settlement - High	RES Settlement - Low	Notes
Non-Net Metering Annual Cost-of-Service	$ 1,841.50	$ 1,841.50	$ 1,841.50	$ 1,841.50	$ 1,841.50	$ 1,841.50	All-in CoS for Customers before solar. Equals costs calculated in Calculations tab plus rider adjustments
Net Metering Annual Cost-of-Service	$ 1,120.73	$ 1,154.35	$ 1,087.10	$ 1,120.73	$ 1,154.35	$ 1,087.10	All-in CoS for Customers after solar. Equals costs calculated in Calculations tab plus rider adjustments
Cost-of-Service Reduction from Solar	$ 720.77	$ 687.15	$ 754.40	$ 720.77	$ 687.15	$ 754.40	
Cost-of-Service Reduction from Solar	$ 720.77	$ 687.15	$ 754.40	$ 720.77	$ 687.15	$ 754.40	
Revenue Reduction	$ 1,266.28	$ 1,304.27	$ 1,228.29	$ 837.62	$ 862.75	$ 812.49	Calculated from SAS model, used 2017 data set to match CoS test year, current rates
Payout for Exports	$ 23.68	$ 22.97	$ 24.39	$ 116.13	$ 112.64	$ 119.61	Removed exports from calculation at unit cost
Net Revenue Reduction	$ 1,242.60	$ 1,281.30	$ 1,203.90	$ 721.49	$ 750.11	$ 692.88	Revenue reduction not including exports
Annual Solar Cross-Subsidy*	$ 521.83	$ 594.15	$ 449.51	$ 0.72	$ 62.96	$ (61.51)	
Monthly Solar Cross-Subsidy*	$ 43.49	$ 49.51	$ 37.46	$ 0.06	$ 5.25	$ (5.13)	
Reduciton in Solar Cross-Subsidy				100%	89%	114%	

DEC

	RS	RS-High	RS- Low	RE	RE- Low	RE-High	RS Settlement	RS Settlement - High	RS Settlment - Low	RE Settlement	RE Settlement - High	RE Settlement - Low
Non-Net Metering Annual Cost-of-Service	$ 1,607.46	$ 1,607.46	$ 1,607.46	$ 1,607.46	$ 1,607.46	$ 1,607.46	$ 1,607.46	$ 1,607.46	$ 1,607.46	$ 1,607.46	$ 1,607.46	$ 1,607.46
Net Metering Annual Cost-of-Service	$ 969.07	$ 998.14	$ 939.99	$ 969.07	$ 998.14	$ 939.99	$ 969.07	$ 998.14	$ 939.99	$ 969.07	$ 998.14	$ 939.99
Cost-of-Service Reduction from Solar	$ 638.40	$ 609.32	$ 667.47	$ 638.40	$ 609.32	$ 667.47	$ 638.40	$ 609.32	$ 667.47	$ 638.40	$ 609.32	$ 667.47
Cost-of-Service Reduction from Solar	$ 638.40	$ 609.32	$ 667.47	$ 638.40	$ 609.32	$ 667.47	$ 638.40	$ 609.32	$ 667.47	$ 638.40	$ 609.32	$ 667.47
Revenue Reduction	$ 1,249.30	$ 1,286.78	$ 1,211.82	$ 1,082.94	$ 1,115.43	$ 1,050.45	$ 882.68	$ 909.16	$ 856.20	$ 675.04	$ 695.29	$ 654.79
Payout for Exports	$ 13.80	$ 13.39	$ 14.22	$ 13.80	$ 13.39	$ 14.22	$ 67.70	$ 65.67	$ 69.73	$ 67.70	$ 65.67	$ 69.73
Net Revenue Reduction	$ 1,235.50	$ 1,273.39	$ 1,197.60	$ 1,069.14	$ 1,102.04	$ 1,036.23	$ 814.98	$ 843.49	$ 786.47	$ 607.34	$ 629.62	$ 585.06
Annual Solar Cross-Subsidy*	$ 597.10	$ 664.06	$ 530.13	$ 430.74	$ 492.71	$ 368.77	$ 176.59	$ 234.17	$ 119.00	$ (31.05)	$ 20.30	$ (82.41)
Monthly Solar Cross-Subsidy*	$ 49.76	$ 55.34	$ 44.18	$ 35.89	$ 41.06	$ 30.73	$ 14.72	$ 19.51	$ 9.92	$ (2.59)	$ 1.69	$ (6.87)
Reduction in Cross-Subsidy							70%	65%	78%	107%	96%	122%

	RS	RE	RS Settlement	RE Settlement	RS Settlement - High	RE Settlement - High	RS Settlement - Low	RE Settlement - Low
Percent of Population	55%	45%	55%	45%	55%	45%	55%	45%
Weighted Solar Cross-Subsidy		$ 43.52		$ 6.93		$ 11.49		$ 2.36
Weighted Reduction in Solar Cross-Subsidy				84%		74%		95%

Rider Adjustments - DEC		Notes
EE/EDIT	$ 0.000946	
Fuel Adjustment from 2017-9/20	$ (0.002664)	Embedded unit costs include fuel rate from 2017, need to update to rates as of 10/1/20 = 0.016102-0.018769
Monthly Leaf 50C Charge	0.64	

Rider Adjustments - DEP		Notes
DSM/EE	$ 0.00671	
Fuel Adjustment from 2017-9/20	$ (0.00282)	Embedded unit costs include fuel rate from 2017, need to update to rates as of 7/1/20 = 0.02456-0.03087
EDIT	$ (0.00349)	
Rider 39 Charge	$ 1.00	

	Current NEM Policy	Settlement
Excess Exports kWh (i.e. kWh credited at avoided cost rate)	595	2,918

Embedded Cost Study

Docket Nos. 2020-264-E & 2020-265-E

Calculation of Cost to Serve Without Adjustments

For the test year ending December 31, 2017

Unit Costs

	unit	DEC
P&T Demand	$/kW-Month	
D Demand	$/kW-Month	$ 1.94
P Demand	$/kW-Month	$ 15.31
T Demand	$/kW-Month	$ 1.33
Energy	$/kWh	$ 0.0232
Customer	$/Month	$ 24.85

DEC

No Solar

Month	Energy	D Demand	T Demand	P Demand	Customer	Total COS
1	$ 28.33	$ 20.03	$ 4.98	$ 57.42	$ 24.85	$ 135.61
2	$ 21.05	$ 20.03	$ 4.98	$ 57.42	$ 24.85	$ 128.33
3	$ 24.59	$ 20.03	$ 4.98	$ 57.42	$ 24.85	$ 131.87
4	$ 21.08	$ 20.03	$ 4.98	$ 57.42	$ 24.85	$ 128.37
5	$ 25.85	$ 20.03	$ 4.98	$ 57.42	$ 24.85	$ 133.14
6	$ 32.98	$ 20.03	$ 4.98	$ 57.42	$ 24.85	$ 140.26
7	$ 43.22	$ 20.03	$ 4.98	$ 57.42	$ 24.85	$ 150.50
8	$ 38.65	$ 20.03	$ 4.98	$ 57.42	$ 24.85	$ 145.93
9	$ 28.32	$ 20.03	$ 4.98	$ 57.42	$ 24.85	$ 135.60
10	$ 23.53	$ 20.03	$ 4.98	$ 57.42	$ 24.85	$ 130.81
11	$ 24.38	$ 20.03	$ 4.98	$ 57.42	$ 24.85	$ 131.66
12	$ 33.00	$ 20.03	$ 4.98	$ 57.42	$ 24.85	$ 140.28
Annual Total	**$ 344.98**	**$ 240.32**	**$ 59.79**	**$ 689.10**	**$ 298.18**	**$ 1,632.37**

	Energy	D Demand	T Demand	P Demand	Customer	Total COS
CoS Savings	$ 111.58	$ 14.41	$ 41.93	$ 483.29	$ -	$ 651.21
% Savings	32%	6%	70%	70%	0%	40%

Net Metering

Month	Energy	D Demand	T Demand	P Demand	Customer	Total COS
1	$ 23.36	$ 18.83	$ 1.49	$ 17.15	$ 24.85	$ 85.67
2	$ 15.40	$ 18.83	$ 1.49	$ 17.15	$ 24.85	$ 77.71
3	$ 17.12	$ 18.83	$ 1.49	$ 17.15	$ 24.85	$ 79.43
4	$ 13.31	$ 18.83	$ 1.49	$ 17.15	$ 24.85	$ 75.62
5	$ 15.39	$ 18.83	$ 1.49	$ 17.15	$ 24.85	$ 77.71
6	$ 19.25	$ 18.83	$ 1.49	$ 17.15	$ 24.85	$ 81.56
7	$ 25.18	$ 18.83	$ 1.49	$ 17.15	$ 24.85	$ 87.50
8	$ 24.11	$ 18.83	$ 1.49	$ 17.15	$ 24.85	$ 86.42
9	$ 17.71	$ 18.83	$ 1.49	$ 17.15	$ 24.85	$ 80.03
10	$ 16.61	$ 18.83	$ 1.49	$ 17.15	$ 24.85	$ 78.92
11	$ 18.82	$ 18.83	$ 1.49	$ 17.15	$ 24.85	$ 81.14
12	$ 27.14	$ 18.83	$ 1.49	$ 17.15	$ 24.85	$ 89.46
Annual Total	**$ 233.40**	**$ 225.91**	**$ 17.86**	**$ 205.81**	**$ 298.18**	**$ 981.16**

Embedded Cost Study
Docket Nos. 2020-264-E & 2020-265-E
Billing Determinants
For the test year ending December 31, 2017

Month	Sum of Exports	Sum of Imports	Sum of Self-Consumption	Gross Load (kWh)	Solar Production
1	399	1,007	203	1,221	601
2	655	664	230	907	885
3	890	738	312	1,060	1,202
4	857	574	329	909	1,186
5	872	664	443	1,114	1,315
6	731	830	588	1,421	1,319
7	674	1,085	770	1,863	1,445
8	569	1,039	622	1,666	1,191
9	693	764	445	1,221	1,138
10	666	716	287	1,014	954
11	463	811	232	1,051	695
12	338	1,170	248	1,422	586
Total	7,807	10,060	4,709	14,870	12,516

Non-Coincident Peaks

Description	
No Solar	10.34
Solar	9.72

Coicident Peaks

	DEP	DEC
Date & Time	7/13/17 5pm	8/17/17 4pm
No Solar	no data	3.75
Solar	no data	1.12

Note: because load data was only avalaible for DEC, DEC peak determinants were used for both utilities.
The DEP peaks are listed above only for reference.

DEC Functional Revenue by Rate
Docket Nos. 2020-264-E & 2020-265-E
SC RETAIL COST OF SERVICE - PROPOSED - 1CP - COMPLIANCE FILING
From Docket No. 2018-319-E
For the test year ending December 31, 2017
Dollars in Thousands

								DISTRIBUTION							Total Dist Demand/
RATE	TOTAL	Production Demand	Production Energy	Transmission	Dist-Substations	Dist-Pole,Tow,Fix	Dist-Conductors	Dist-Transformers	Dist-Other Local	OTHER	Total Distr Demand	Dist-Customer	Total Distribution	DNCP	DNCP
	a	b	c	d	e	f	g	h	i	b	j	k	l	m	n
RS1	394,586	176,840	75,977	15,347	10,042	8,081	16,712	9,770	27	76,818	44,632	81,790	126,422	1,892,350	4.32
RT	638	304	156	26	15	11	25	14	0	-	65	86	151	3,009	2.17
RE1	307,307	118,006	68,096	10,236	10,273	7,826	17,117	9,470	361	28,983	45,048	65,921	110,969	1,966,086	2.29
Total RS	**702,531**	**295,151**	**144,229**	**25,609**	**20,331**	**15,919**	**33,854**	**19,253**	**388**	**105,802**	**89,745**	**147,797**	**237,542**		
TOTAL RETAIL	1,706,789	787,120	486,938	68,908	36,659	29,741	63,254	27,612	22,589	#N/A	179,855	183,968	363,823	6,987,517	2.57

		Cost (not in thousands)	Annual Units		Unit Cost per Month
Customer	$	147,797,289	5,947,908	$	24.85
P Demand	$	295,150,765	1,606,176	$	15.31
T Demand	$	25,609,064	1,606,176	$	1.33
D Demand	$	89,745,114	3,861,445	$	1.94
Energy	$	144,228,770	6,206,954,000	$	0.0232
overall total	$	702,531,002			

	Total RS
MWHS AT METER	
MWHs at Meter	6,206,954
NON-COINCIDENT PEAK	
NCP	3,861,445
NUMBER OF CUSTOMERS	
Number of Customers	495,659
(not in thousands)	
PRODUCTION DEMAND	
Production Demand	1,606,176

Souce: DEC Allocators from SC Retail Cost of Service- Proposed - 1CP - Compliance Filing

DEP Functional Revenue By Rate
Docket Nos. 2020-264-E & 2020-265-E
From DOCKET NO. 2018-218-E "ADJUSTED BY FUNCTION WITH COMPLIANCE RATES ANNUALIZED"
SOUTH CAROLINA RETAIL COST OF SERVICE STUDY
ADJUSTED TEST YEAR ENDING DECEMBER 31, 2017

UNIT DETAIL - REVENUES		Unit Cost Classification	SC RETAIL	SC RES excl TOU	SC RES TOU
FUNCT REQ'TS RATE SCHED REV incl. ASK: Incr. (Decr.)	PROD_DEMAND	Product & Trans Demand	221,794,781	84,460,810	1,588,673
	PROD_ENERGY	Energy	226,470,785	78,726,632	1,595,259
	TRANSMISSION	Product & Trans Demand	24,061,158	8,765,785	159,600
	DIST_SUBS	Distribution Demand	10,954,293	5,482,623	81,806
	DIST_PRIMARY	Distribution Demand	12,047,505	6,631,195	99,719
	DIST_L_XFMR	Distribution Demand	6,125,895	3,323,302	49,077
	DIST_SEC_SERV	Distribution Demand	19,883,544	2,572,841	38,711
	CUSTOMER	Customer	56,469,352	44,228,779	560,089
	Total		577,807,313	234,191,968	4,172,933
Billing Determinants	Summer CP kW (DP adj @ meter)		1,610,108	458,926	8,994
	Adj kWh Sales (E2 at meter)		8,241,813,840	1,978,209,443	40,124,603
	Year End No. Cust (C1)		304,233	134,234	1,712

SC Res NCP CY 2017 1,241,969

	Unit Cost		Notes
Customer ($/month)	$	27.46	Costs/Number of Customers
Distribution Demand ($/kW-Month)	$	1.23	Costs/SC Res NCP CY 2017/12
Production and Trans Demand ($/kW-Month)	$	16.91	Costs/Summer CP kW
Energy ($/kWh)	$	0.03980	Costs/Adj kWh Sales